Lithofacies and petrophysical properties of Mesaverde tight-gas sandstones in Western U.S. basins

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Project title:
Analysis of Critical Permeability, Capillary and Electrical Properties for Mesaverde Tight Gas Sandstones from Western U.S. Basins

US DOE # DE-FC26-05NT42660

website: http://www.kgs.ku.edu/mesaverde
Project objectives

- provide a large database of basic petrophysical properties for TGS ("the sandbox"), tied to detailed lithofacies descriptions
- investigate capillary pressure as function of NCS and drainage vs. imbibition behavior
- investigate critical gas saturation and residual gas saturation
- investigate electrical properties, FRF, m, as $f(\phi, \text{salinity})$
- provide it all as a web-accessible database (public domain data)
Sampling

- systematic characterization of Kmv lithofacies over entire Rocky Mtn region
- 44 wells/6 basins
- Described 7000 ft core (digital)
- 2200 core samples
- 120-400 advanced properties samples
What’s in the sandbox?

- core descriptions (digital, 0.5’ step) with LAS log data files
- thin section petrography (photos, point counts)
- basic core analysis (routine & 4000 psi NCS)
  - porosity, permeability, PV compressibility
- Hg capillary pressure (150 unconfined, 90 at NCS, and 37 scanning curves)
- Formation resistivity factor at 4 salinities
- Critical gas saturation at percolation threshold
Digital Core Description

- To provide lithologic input to equations and predict lithology from logs used 5 digit system
  - 1 basic type (Ss, Ls, coal)
  - 2 grain size/sorting/texture
  - 3 consolidation
  - 4 sedimentary structure
  - 5 cement mineralogy
- Property continuum - not mnemonic or substitution cipher
- Similar to system used in 1994 and subsequent studies
Core description

- rock typing at 0.5 ft frequency to match log data resolution
- lithology, color, grain size, sed structures
- sample locations
- important cements
- depositional environments
Petrography

- ~150 advanced properties samples were petrographically characterized
- representative photos at several magnifications
- point counts

Williams PA 424, 6148.8’ 15276
9.9% 2.66 g/cc Ka=0.0237 mD
Sample QA & distributions

- Petrophysical property distributions are generally normal or log-normal.
- Sub-distributions = \( f \) (basin, lithofacies, marine/non-marine, etc.)
Permeability vs Porosity

- Overall trend allows prediction of $K_{ik}$ from porosity with 10X error
- Breaking into two subtrends at $\phi \sim 12\%$ improves to 5X error
- Different $k$-$\phi$ trends among basins
- Beyond common $k \uparrow$ with grain size $\uparrow$, lithologic influence changes are complex and nonlinear
Pore Volume Compressibility

- Previously documented in literature
- no large datasets in public domain
- 113 Samples
- Log-linear pore volume change seen in EVERY sample, avg. $R^2 = 0.99$
- characteristic of cracks/sheet-pores
- Slope and intercept increase with increasing porosity
We’ve known for many years that low-K sandstones are stress sensitive

1997 Byrnes equation:

\[
\log k_{ik} = 1.34 \log k_{air} - 0.6
\]

this dataset \( n = 2062 \)

Statistically similar except for \( k > 1 \text{ mD} \)

no meaningful stress dependence over 10 mD

\[\log k_{ik} = -0.0088 (\log k_{air})^3 - 0.072 (\log k_{air})^2 + 1.37 \log k_{air} - 0.46\]
Capillary pressure

- investigated $P_c$ as $f$ (lithology, $\phi$, $K$)
  - 120 high-low pairs
  - sampled across basins, permeability range, & lithology

- stress sensitivity of $P_c$
  - most MICP curves are run under laboratory conditions, but given stress dependence of permeability we expect $P_c$ to also be stress sensitive

- relationship between initial and residual non-wetting phase saturations (“scanning curves”) 
  - only published data are for conventional reservoir rocks
Capillary Pressure Measurement

- Three different air-Hg measurements
  - Unconfined (n=150)
  - In-situ drainage only (n=90)
  - In-situ drainage – imbibition (n=37)
    - NES = 4000 psi
Unconfined Capillary Pressure

- Capillary pressure varies with lithofacies and associated pore size distribution and permeability.
Normalization: Leverett J Function

- J function works poorly for mixed lithofacies and between basins
- Does work OK for single lithofacies in a small area
- Works very well for a single sample, stressed vs. unstressed
Stress effect on Pc

- no significant difference in high-low pairs at high K
- increasing Pce separation with decreasing K
- merging of curves at 35-50% Sw
- users of Winland R35 need to adjust for confining stress
Threshold entry pressure is predictable from $\sqrt{K/\phi}$ at any confining pressure.

Correct unconfined $P_{ce}$ to insitu $P_{ce}$ based on perm change with stress.
Drainage-Imbibition Pc

- what is the residual trapped gas when a reservoir leaks or is along a gas migration path?
Trapping increases with increasing initial saturation

(after Lake 2005)
Residual Gas Saturation

- Land equation:
  \[ C = \frac{1}{(Sn_{wr} - Swi) - \frac{1}{(Sn_{wi} - Swi)}} \]
  \[ Sn_{wr} = \frac{1}{C + \frac{1}{Sn_{wi}}} \]

- C \approx 0.54 to 0.66
Drainage-Imbibition Pc

- is this the answer to the “Pinedale problem” we saw earlier?

![Graph showing drainage and imbibition phases with various labels and markers.](image-url)
Critical Gas Saturation

- Experimental work indicates $S_{gc} < 10\%$, often $< 5\%$
- *but* $K_{rg}$ curves extrapolate to $35\% < S_{gc} < 10\%$

**Issues**
- little $k_{rg}$ data at $S_{w} > 65\%$
- two different ways to model the data, which is better?
Critical Nonwetting Phase Saturation

- Electrical conductivity and Pc inflection indicate $0\% < S_{gc} < 22\%$
- Higher $S_{gc}$ as bedding complexity increases
Sgc and percolation theory

- Critical gas saturation strongly controlled by sedimentary structures/rock fabric
- Any bedding parallel laminations result in low Sgc

Experimental results can be explained using four - pore network architecture models

1) Percolation Network (N_p) - Macroscopically homogeneous, random distribution of bond sizes, e.g., Simple Cubic Network (z=6)

2) Parallel Network (N_p) - preferential orientation of pore sizes or beds of different N_p networks parallel to the invasion direction.

3) Series network (N_s) - preferential sample-spanning orientation of pore sizes or beds of different N_s networks perpendicular to the invasion direction.

4) Discontinuous series network (N_d) - preferential non-sample-spanning orientation of pore sizes or beds of different N_d networks perpendicular to the invasion direction. Represents continuum between N_s and N_d.

Experimentally, water capillary pressure (kPa) vs. water saturation shows critical gas saturation.
Archie’s equation

$$S_w^n = \left( \frac{a}{\phi^m} \right) \ast \left( \frac{R_w}{R_t} \right)$$

- completely empirical – no theoretical basis
- “m” is the porosity or cementation exponent
  - generally considered related to “tortuosity” or length of the current flow path; better thought of as electrical efficiency of the path
- “n” is the saturation exponent
  - related to change in conductivity path with changing saturation
Archie porosity exponent

- for a simple bundle of capillary tubes oriented parallel to current flow direction: $m \rightarrow 1$
  - insensitive to cross section shape, so fractures will act like capillary tubes

- as porosity increases there is more dead space outside the conductive path, so $m \uparrow$

- for an “average” sandstone comprised of spherical grains, $m \rightarrow 2$
Capillary tube model for m

Conductivity = $C_w$

Conductivity = $C_w \phi$

$m = 1$

after Herrick & Kennedy, 1993, SPWLA Paper HH
When $F$ and $\phi$ are plotted log-log.

$\log F = -m \log \phi$
FRF vs. $\phi$ for Mesaverde

40K ppm dataset, n=310
Porosity dependence of $m$

- **Empirical:**
  \[ m = 0.676 \log \phi + 1.22 \]
  \[ R^2 = 0.63 \text{ (RMA)} \]
- **Limit $m = 1.95$**
- **No significant increase above 12% porosity**
behavior is contrary to expectations.....

- but only because we call it the “cementation exponent”

Shell equation for $m$

“cementation exponent” vs. porosity

after Neustaedter, 1968, SPE 2071
Dual porosity model

- $m = \log[\phi_1^{m_1} + \phi_2^{m_2}]/\log \phi_t$
  - $\phi$ expressed as v/v
  - $\phi_2 = 0.0035$, $m_1=2$, $m_2=1$; SE both = 0.11
  - rock behaves like a mixture of matrix porosity and cracks, with cracks dominating low porosity samples

- cap at $m = 1.95$ ($\phi \sim 16\%$)
- both models fit data

$\phi_t$ = total porosity, $(\phi_1 + \phi_2)$
$\phi_1$ = matrix porosity
$m_1$ = matrix cementation exponent
$\phi_2$ = fracture porosity
$m_2$ = fracture cementation exponent

40K ppm brine data
Archie porosity (cementation) exponent

- Nearly all cores exhibit some salinity dependence
- Tested plugs with 20K, 40K, 80K, and 200K ppm brines
All data, all salinities
Data, presentations and reports are on our project website:

http://www.kgs.ku.edu/mesaverde

also accessible via

http://www.discovery-group.com

Questions?